Permeability, Porosity & Skin factor

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Content

Preface

Preface

This assignment deals with the properties which are considered to be fundamental in petroleum engineering. The properties discussed are the porosity -a measure of avoid space in a rock; the permeability-a measure of the fluid transmissivity of a rock and I will talk about the skin factor -its meaning and effect.

I know that it's difficult to discuss those important and fundamental topics in limit pages but, I will do my best to make it clearly and nicely assignment with some graphs and charts.

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1.0 Porosity

Porosity is the ratio of the pore volume to the bulk volume of the reservoir rock on percentage basis. That is

$$\text{Percentage porosity} = \frac{porevolume}{bulkvolume} \times 100$$

Bulk volume = the total volume of the rock
Pore volume = the volume of the pores between the grains

The measurement of porosity is important to the petroleum engineer since the porosity determines the storage capacity of the reservoir for oil and gas. It is necessary to distinguish between the (1) absolute porosity of a porous medium and its (1) effective porosity. In porous rocks there will always be a number of blind or unconnected pores. Absolute porosity includes these pores as well as those open to the flow of fluids whereas the effective porosity measures only that part of the pore space that is available to fluid flow(as discussed later). The figure below shows the arrangement of pores in a piece of rock.

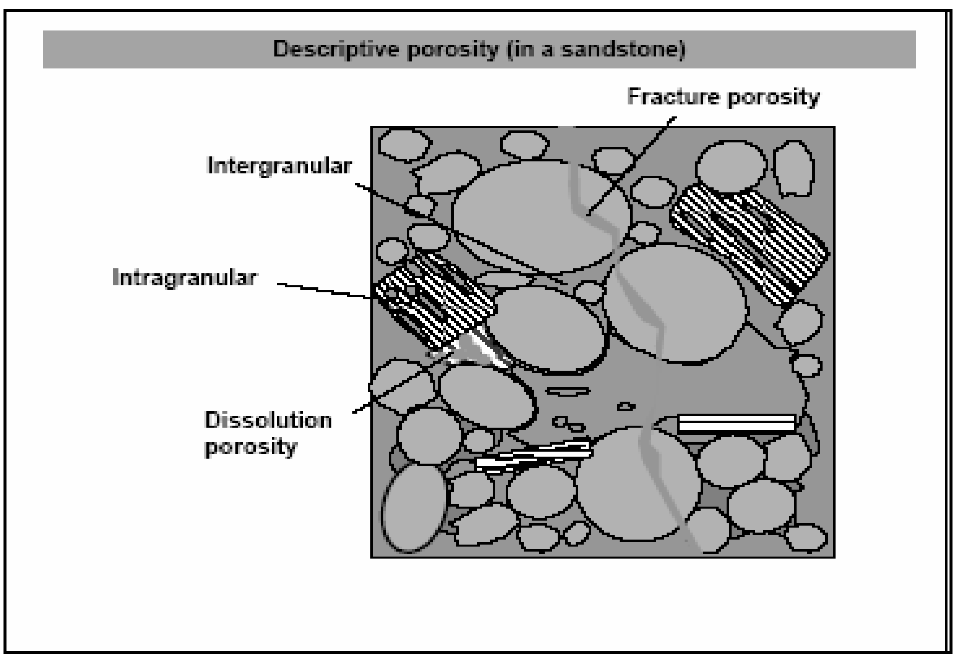

Fig.1

If the shape of the rock is uniform the bulk volume may be computed from measurements of the dimensions of the rock.

1.1 Classification of Porosity

Pores are classified based on their morphological viewpoint as:

Catenary or inter connected pore: This type of pore has more than one throat connected with other pores and extraction of hydrocarbon is relatively easy from such pore, as shown in Fig. 2.

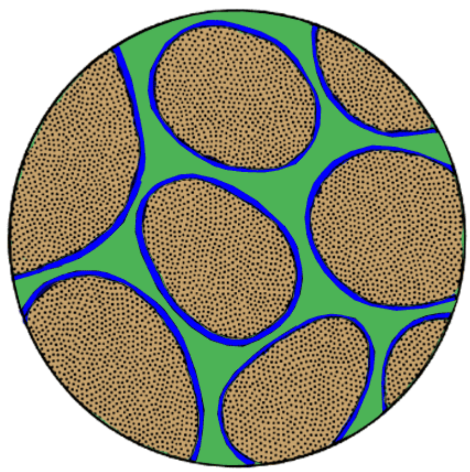

Fig. 2: Interconnected pore

Cul-de-sac or connected or dead end: This type of pore has one throat connected with other pores. It may yield some of the hydrocarbon by expansion as reservoir pressure drops as shown in Fig. 3.

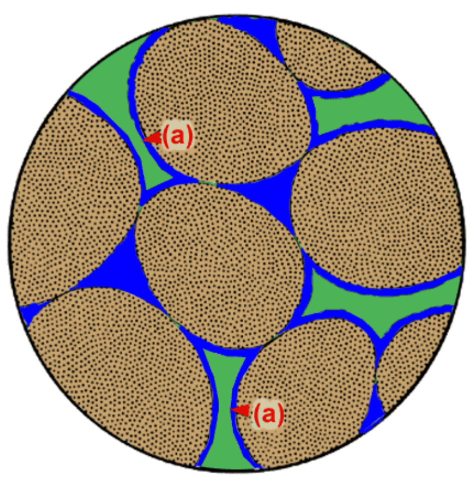

Fig. 3: Dead end pore

Closed or isolated pore: This type of pore is closed. It does not have throat and cannot connect with other pore. It is unable to yield hydrocarbons in normal process as shown in Fig. 4.

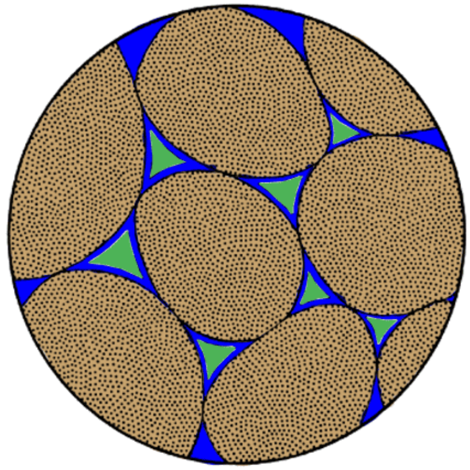

Fig.4

Effective porosity
The ratio of the volume of interconnected pore to the total volume of reservoir rock is called effective porosity.

Ineffective porosity
The ratio of the total volume of closed pore to the bulk volume is termed as ineffective porosity.

Thus the absolute or total porosity = effective porosity + ineffective porosity
Interconnected and connected pores constitute effective porosity because hydrocarbons can move out from them. In the case of interconnected porosity, oil and gas flowing through the pore space can be flushed out by a natural or artificial water drive. Connected porosity is unaffected by flushing but may yield some oil or gas by expansion, as reservoir pressure drops. Reservoirs with isolated porosity are unable to yield hydrocarbons. Any oil or gas contained entered the pore spaces before they were closed by compaction or cementation. Thus, isolated porosity contributes to the total porosity of rock but not to the effective porosity.

1.2 Classification of Porosity based on their time of deposition
Reservoir Pores are found as two distinct general types in sedimentary rocks based on their time of formation. These are: (1) Primary, or Intergranular or Depositional Porosity and (2) Secondary, or Intermediate or Post-depositional Porosity.

Each type of the pore has subdivisions, which can be summarized in Table 1 below:

Table 1: Classification of different type of formation

Main type (Time of formation)	Sub-type	Origin
Primary or Depositional	Intergranular, or Interparticle Itragranular, or intraparticle	Sedimentation
	Intercrystalline Fenestral	Cementation
Secondary or Post-depositional	Vuggy Modic	Solution
	Fracture	Tectonics, Compaction, Dehydration, Diagenesis*

Primary Porosity

Primary porosity is divisible into two types: intergranular or interparticle porosity, which occurs between the grains of a sediment (Fig. 5) and intragranular or intraparticle porosity-

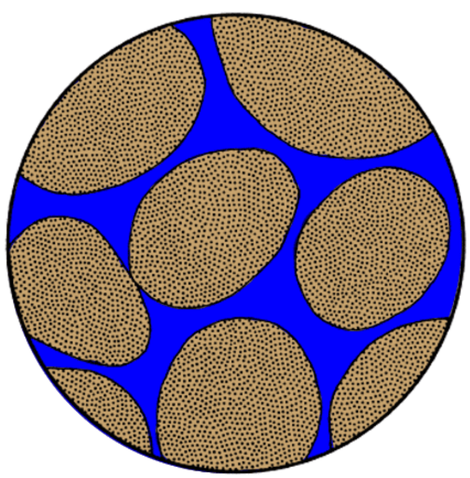

Fig. 5

* **Diagenesis**: The changes that take place in a sediment as a result of increased temperatures and pressures, causing solid rock to form, for example, as sand becomes sandstone

This actually occurs within the sediment grains them selves (Fig. 6)

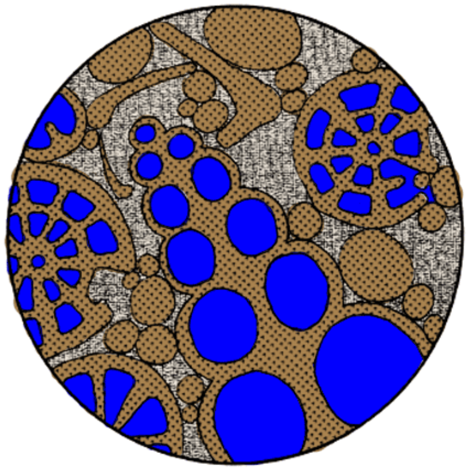

Fig. 6

Intergranular porosity is more typical of sandstones. It is also generally found within newly-deposited lime sand. However, in lime sands it is seldom preserved because of porosity loss by cementation.

With intergranular porosity, the pore spaces are connected, one to another, by throat passages (Fig. 5). Unless there is extensive later cementation, reservoirs with intergranular porosity generally have both good interconnected porosity and good permeability. Effective porosity in these reservoirs is equivalent to total porosity.

Intragranular porosity is more typical of newly-deposited skeletal lime sands. Fig. 6 is a sketch of a thin section of a limestone reservoir showing pore spaces within skeletal grains. It is unusual for such pores to be preserved. They are generally infilled during early burial by cementation but, in some cases, the cement may be leached out to leave the original intraparticle pore.

Secondary Porosity

Secondary porosity is porosity formed within a reservoir after deposition. The major types of secondary porosity are:

- Fenestral;
- Intercrystalline
- Solution (moldic and vuggy);
- Fracture

Fenestral porosity is developed where there is a gap in the rock framework larger than the normal grain-supported pore spaces. Fenestral porosity is characteristic of lagoonal pelmicrites in which dehydration has caused shrinkage and buckling of the laminae. This type of porosity is less frequently encountered.

Intercrystalline porosity occurs between crystals and is the type of porosity found in several important oil and gas fields. In recrystallized limestones, intercrystalline porosity is negligible. However, crystalline dolomites often possess high intercrystalline porosity.

Fig. 7 is a sketch of a thin section of a crystalline dolomite reservoir. These reservoirs are usually composed of secondary dolomite formed by "dolomitization", the process whereby a pre-existing calcium carbonate deposit is replaced by dolomite.

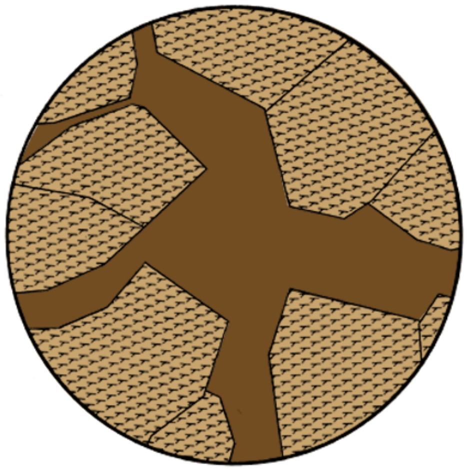

Fig. 7

It is this type of intercrystalline porosity that gives secondary dolomites their characteristic saccaroidal (sugary) texture, and can make them such good reservoirs.
Several types of secondary porosity can be caused by solution. This is a critical process in developing porosity in carbonates, but it can develop secondary porosity in sandstones as well. There are several ways the solution process actually occurs.
Figure 8 shows secondary solution pores developed in a limestone.

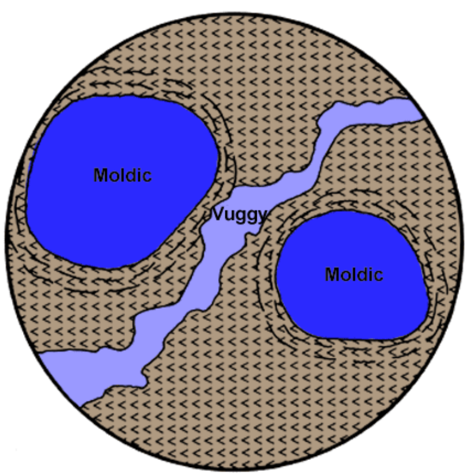

Fig. 8

Some of the pores are round. These are where pellets of lime mud have been leached out. This type of fabric-selective porosity is referred to as moldic, and these pore, therefore, as pelmoldic. Some irregular pore spaces which crosscut the original fabric of rock should also be noted. These pores are known as vugs and the porosity is referred to as vuggy.
If limestone has undergone extensive solution, the vugs may become very large, or cavernous. With solution porosity the adjacent pore spaces may not be connected; there

fore, the effective porosity may be much lower than the total porosity, and the permeability may also be low. Cavernous pores up to five meters high are found in the Fusselman limestone of the Dollarhide field of Texas (Stormont, 1949) and in the Arab D Jurassic limestone of the *Abqaiq* field, Saudi Arabia (McConnell, 1951).

The last significant type of secondary porosity is fracture porosity. Fractured reservoirs can occur in any brittle rock that breaks by fracturing rather than by plastic deformation. Thus, there are fractured reservoirs in shales, hard-cemented quartzitic sandstones, limestones, dolomites and, of course, basement rocks such as granites and metamorphics. As shown in Fig. 9, fractures may develop from tectonic forces associated with folding and faulting.

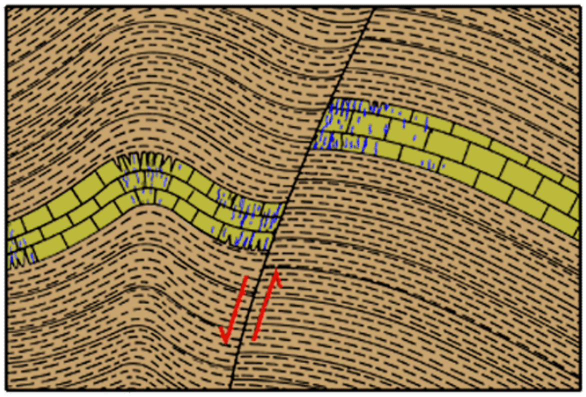

Fig. 9

They may also develop from overburden unloading and weathering immediately under unconformities. Shrinkage from cooling of igneous rocks and dehydrating of shales also causes fracturing.

Fractures are generally vertical to sub vertical with widths varying from paper thin to about 6 mm (Fig. 10). When this type of porosity is developed, the reservoir may have an extremely high permeability, although the actual porosity may not be very high.

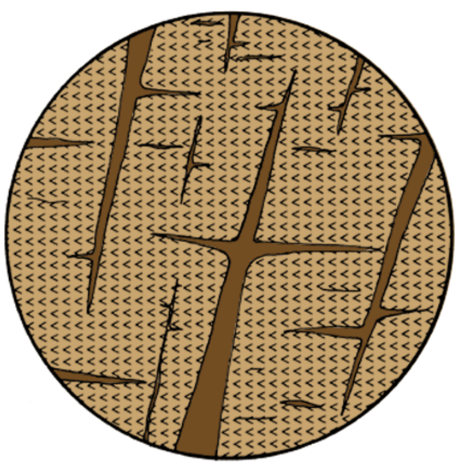

Fig. 10

One must be able to distinguish between fracture porosity and porosity which occurs within the rock itself. Very often fractures are an important part of storage capacity, and sometimes only oil or gas from the fracture pore space itself is actually produced. Fracture porosity can result in high production rates during initial testing of a well, followed by a rapid decline in production thereafter. When a rock has been fractured, the fractures do not necessarily remain open. They may be in filled by later cementation by silica, calcite or dolomite (Fig. 11).

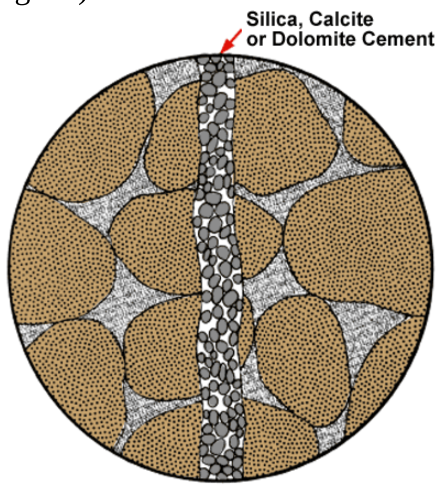

Fig. 11

Fig.12 shows the relation between porosity and reservoir frequency.

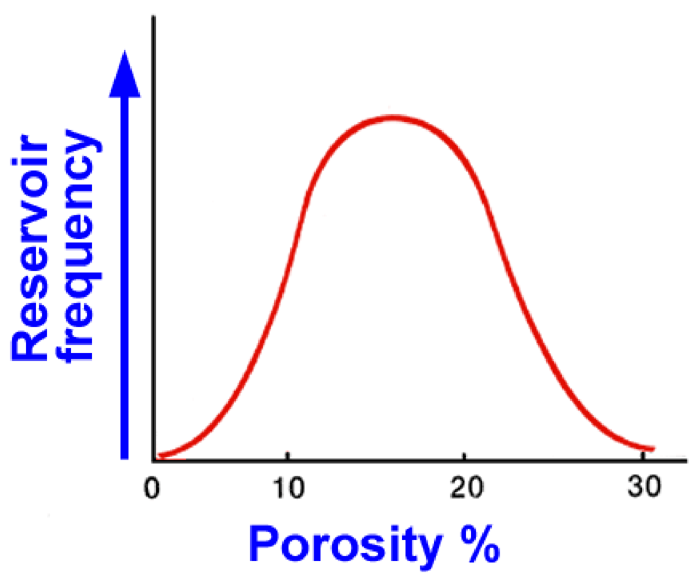

Fig.12

Any porosity less than five percent is very seldom commercial, and any porosity over thirty-five percent is extremely unusual. Porosity can be measured in the laboratory from cores and down the borehole using well logs, especially the sonic, density and neutron logs. Occasionally, it can be estimated from seismic data (as I will discuss later).

Development of Secondary porosity

Secondary porosity is caused by the action of the formation fluids or tectonic forces on the rock matrix after deposition.

For instance, slightly acidic percolating fluid may create and enlarge the pore spaces while moving through the interconnecting channels in the limestone formation by dissolving its materials and create vugs (small caves), moldic or cavernous pore.

Secondary porosity is, however, usually resulted from and/or modified by

Solution
Fractures and joints
Recrystallization and dolomitization
Cementation and compaction

1.3 Laboratory Measurement of Porosity

Bulk volume is first determined by displacement of liquid, or by accurately measuring a shaped sample and computing its volume.
Then any of the following methods are used to measure either the pore volume or grain volume.
1. Summation of Pore Fluids – involves independent determination of gas, oil and pore water volumes from a fresh core sample. The pore volume is determined by adding up the three independent volumes.
2. Washburn-Bunting Method – measures pore volume by vacuum extraction and collection of the gas (usually air) contained in the pores.
3. Liquid Resaturation – pores of a prepared sample are filled with a liquid of known density and the weight increase of the sample is divided by the liquid density.
4. Boyle's Law Method – involves the compression of a gas into the pores or the expansion of gas from the pores of a prepared sample. Either pore volume or grain volume may be determined depending upon the porosimeter and procedure used.
5. Grain Density – measures total porosity. After the dry weight and bulk volume of the sample are determined, the sample is reduced to grain size and the grain volume is determined and subtracted from the bulk volume.

Another method of porosity determination is by petrographic analysis of thin sections of a rock sample. This is done by point counting of pores under a microscope. Impregnation of the sample in a vacuum with dyed resin facilitates pore identification.

A common source of porosity data are the well logs. Porosity may be calculated from the sonic, density, and neutron logs. These three logs are usually referred to as porosity logs. Porosity may also be obtained from the resistivity logs.
Fig.13 below shows some devices used to determining porosity.

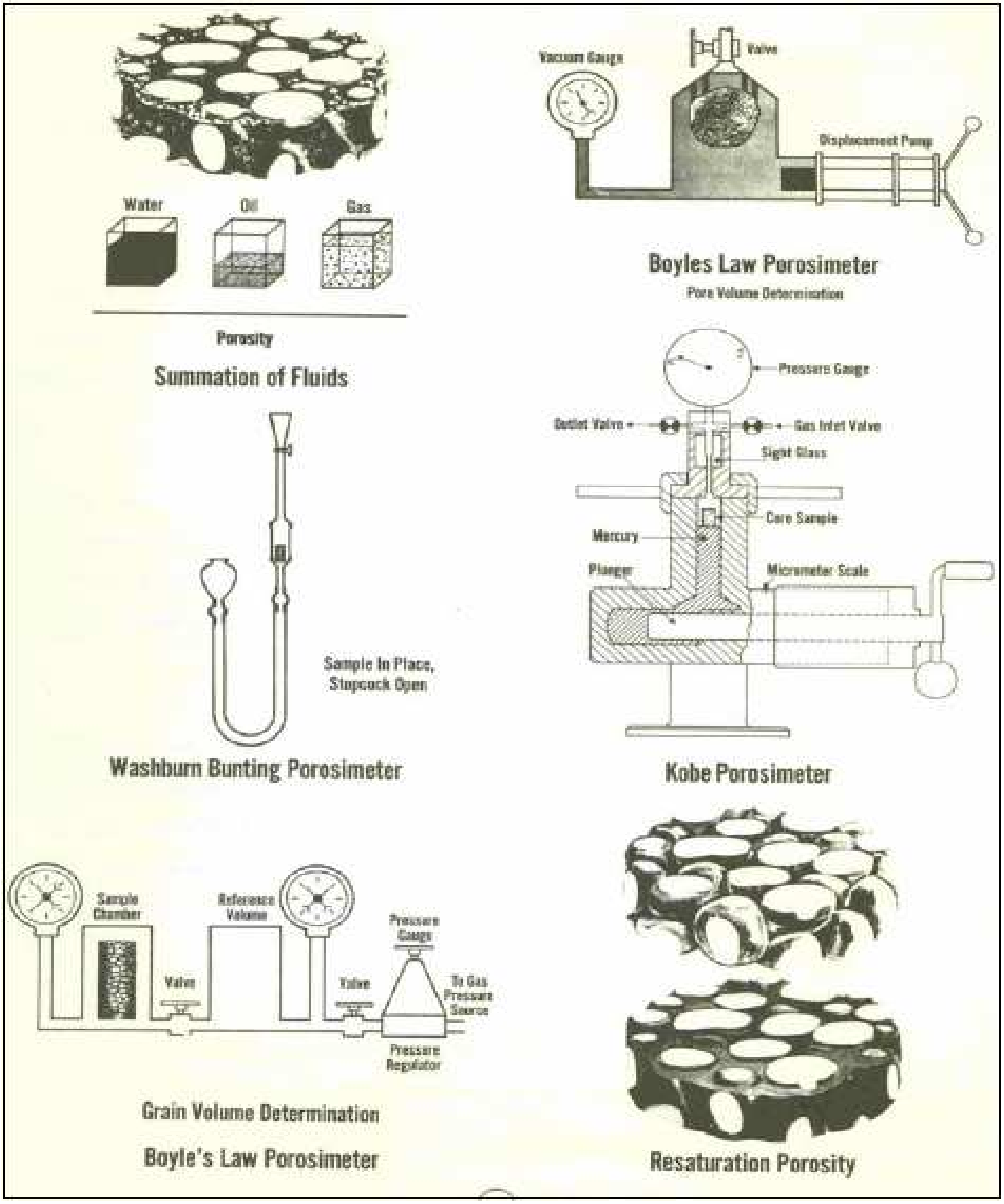

Fig.13

1.4 Porosity ranges

Fig.14 shows how porosity ranges in rocks.

Porosity Ranges

Sand and gravel	20-50 %
Till	10-20 %
Silt	35-50 %
Clay	33-60 %
Clastic sediments	typically 3-30 %
Limestone	<1 to 30 %
Basalt	1-12 %
Tuff	14-40 %
Pumice	- 87 %
Fractured crystalline rock	1-5 %
Unfractured crystalline rock	~0.1 %

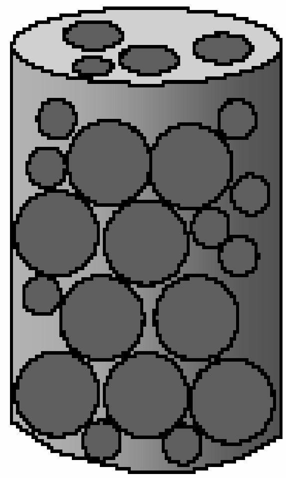

Fig.14

2.0 Permeability

Permeability: is a measure of a rock's ability to conduct fluids.
Figu.15 shows how the permeability of a rock sample can be measured.

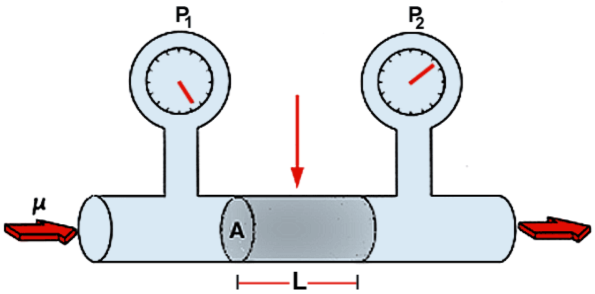

Fig.15: Permeability measurement

A fluid of known viscosity is pumped through a rock sample of known cross-sectional area and length. The pressure drop across the sample is measured through pressure gauges.
The unit of permeability is the *Darcy*. A rock having a permeability of one Darcy allows a fluid of one centipoises (CP) viscosity to flow at a velocity of one centimeter per second for a pressure drop of one atmosphere per centimeter. The formula for Darcy's Law as formulated by Muskat and Botset is as follows:

$$q = \frac{k(P_1 - P_2)A}{\mu L}$$

Where:
q = rate of flow
k = permeability
(P1 - P2) = pressure drop across the sample
A = cross-sectional area of sample
μ= viscosity of fluid
L = length of the sample
Since most reservoirs have permeabilities that are much less than a Darcy, the *millidarcy* (one thousandth of a Darcy) is commonly used for measurement. Permeability is generally referred to by the letter *k*.
In the form shown above, Darcy's law is only valid when there is no chemical reaction between the fluid and rock, and when there is only one fluid phase present completely filling the pores. The situation is far more complex for mixed oil or gas phases, although we can apply a modified Darcy-type equation. Average permeabilities in reservoirs commonly range from 5 to 500 millidarcies. Some reservoirs, however, have extremely high permeabilities. Some of the Cretaceous sandstone reservoirs of the *Burgan field* in Kuwait, for example, have permeabilities of 4,000 millidarcies (Greig, 1958).
Since flow rate depends on the ratio of permeability to viscosity, gas reservoirs may be able to flow at commercial rates with permeabilities of only a few millidarcies. However, oil reservoirs generally need permeabilities in the order of tens of millidarcies to be commercial. Fanall, you must note that *the permeability is a property of a rock not of the fluid.*

2.1 Classification of permeability

Absolute Permeability (k):

Permeability of a rock to a fluid when the rock is 100% saturated with that fluid.

Effective Permeability (k_e):

It has been found that in sand containing more one fluid the presence of one materially impedes the flow of the other. This has given rise to the use of the term *effective permeability* impedes, which may be defined as the apparent permeability to a particular phase (oil, gas or water) or saturation with more than one phase. The amount that flow is impeded depends upon the saturation of the fluids in the sand. The lower the saturation of a particular fluid in the sand, the less readily that fluid flows; or, stated in another way, the lower the saturation of particular fluid in sand, the lower is the effective permeability to that fluid.

Relative Permeability (k_r):

Relative permeability is another term used in reservoir calculation. Relative permeability is the ratio of the effective permeability to a particular phase to the normal (absolute) permeability of the sand. The unit of effective permeability is the Darcy while the relative permeability is being a ratio, has no unit.

2.2 Laboratory Measurement of Permeability

Laboratory measurement of permeability usually uses air as the flow fluid and thus the value obtained is permeability to air (K_{air}). Common device that may used to determining (k) is shown below.

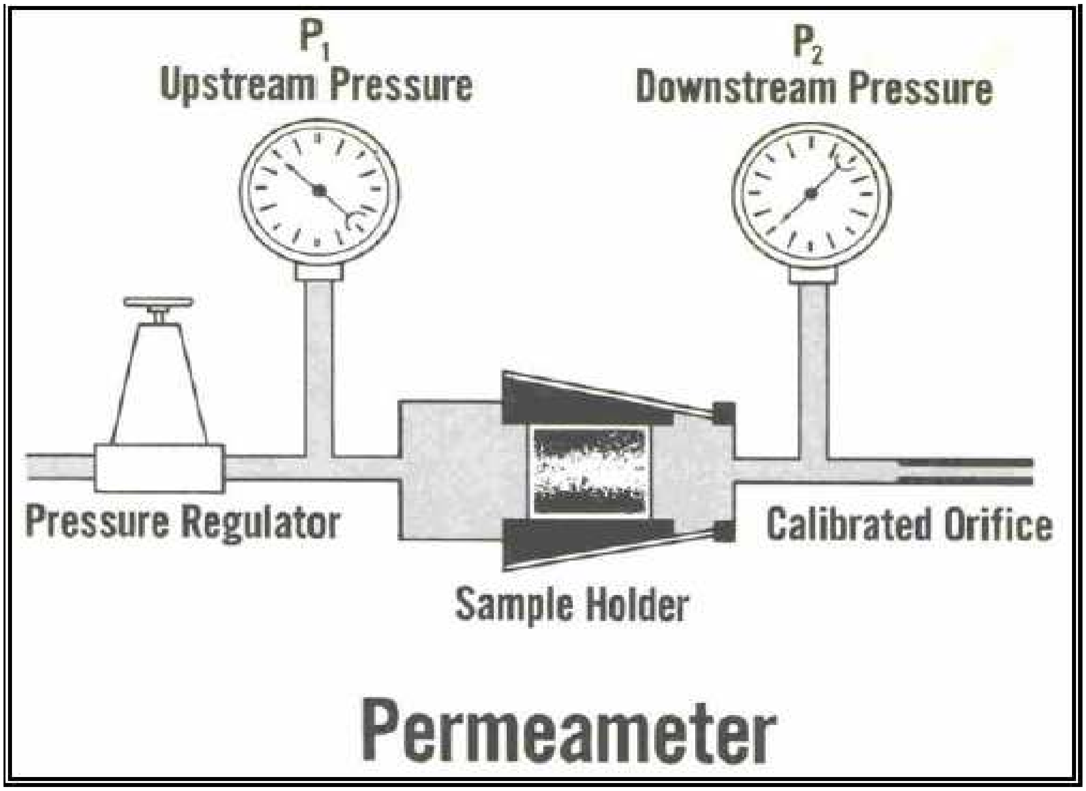

Fig.15

Permeability values may also be obtained from results of the following flow test
1-RFT – repeat formation test.
2- DST – drill stem test.
New methods of quantification of permeability using well logs are also being developed:
1- Resistivity Gradient.
2- Porosity and Water Saturation.

3.0 Relation between Porosity and permeability

Many investigators have attempted to correlate permeability to porosity, grain size and shape, and packing. The most frequently used relation was developed by Kozeny as follows:
$k = \Phi^3 / (5 \times Sv \times (1-\Phi)^2)$
k = permeability, cm^2 (= 1.013×10^8 Darcies)
Φ = effective porosity
Sv = total grain surface/unit volume of reservoir, cm^2/cm^3
The following figures show the relationship of grain size (Fig.16) and sorting (Fig.17a) & (Fig.17b) to porosity and permeability.
(Fig.16) porosity, permeability and grain size. Porosity is not affected by grain size but permeability increases with increase in grain size.
(Fig.17a) & (Fig.17b) Porosity and permeability are affected by sorting, both increases with better sorting.

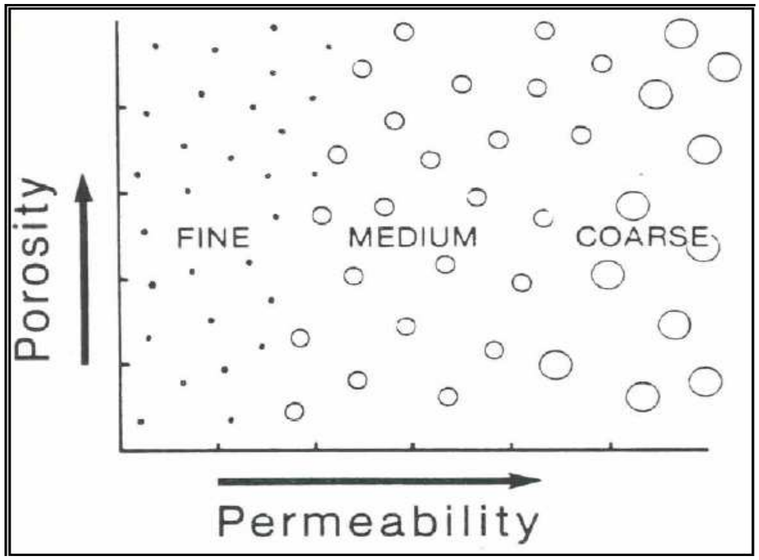

Fig.16

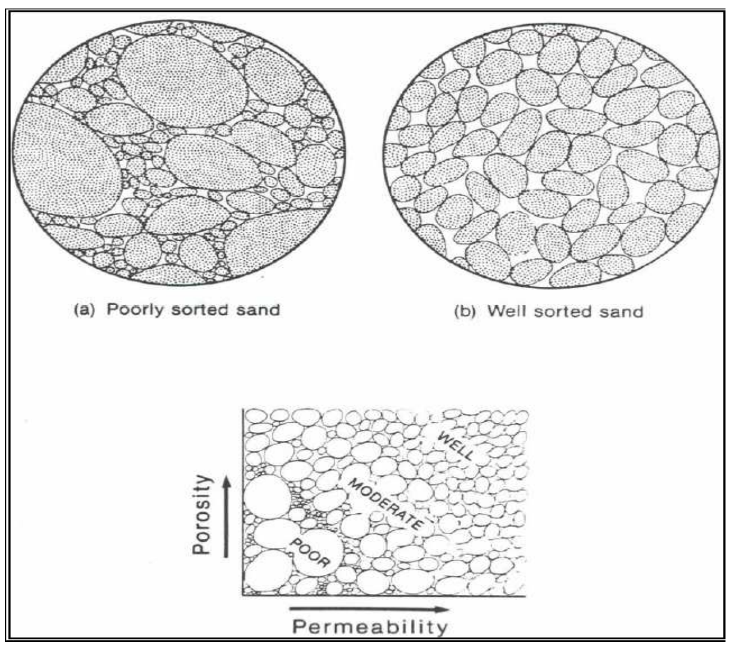

Fig.17a

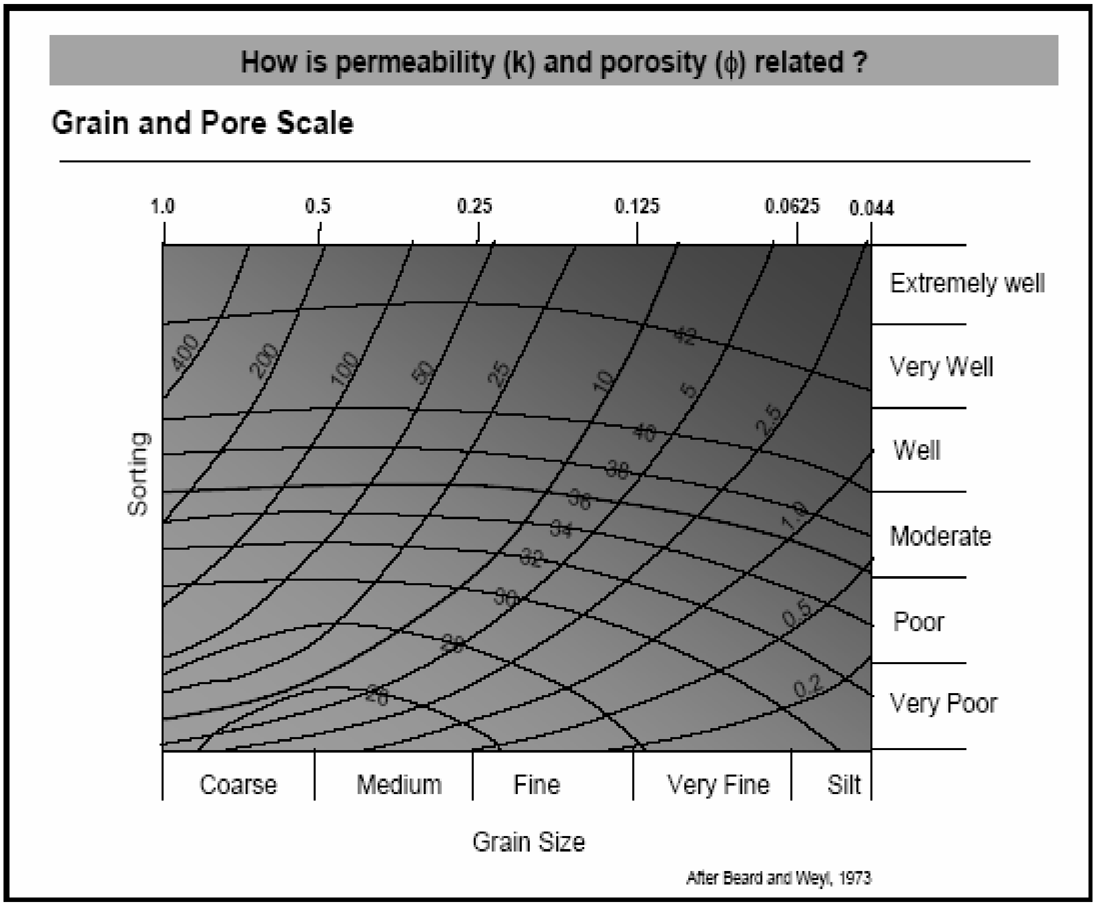

Fig.17b

4.0 Skin Factor

4.1 Introduction

The well skin effect is a composite variable. In general, any phenomenon that causes a distortion of the flow lines from the perfectly normal to the well direction or a restriction to flow (which could be viewed as a distortion at the pore-throat scale) would result in a positive value of the skin effect.

Positive skin effects can be created by “mechanical” causes such as partial completion (i.e., a perforated height that is less that is less than reservoir height) and inadequate number of perforations (again , causing a distortion of flow lines), by phase changes (relative permeability reduction to the main fluid) , turbulence,and,of course, by damage to the natural reservoir permeability.

A negative skin effect denotes that the pressure drop in the near-well bore zone is less than would have been from the normal, undisturbed, reservoir flow mechanisms. Such a negative skin effect, or a negative contribution to the total skin effect, may be the result of matrix stimulation (the near-well bore permeability exceeds the normal value), hydraulic fracturing, or a highly inclined well bore.Finally,note that *while the skin effect is dimensionless, the associated damage zone is not* .

4.2 Description of Damage and Stimulation

The processes of drilling, completing and producing an oil or gas well include many mechanical, hydraulic, and chemical processes. Many wells are drilled overbalanced, so that drilling fluids migrate into the near-well area. The fine particles in the muds may plug pore throats, or the filtrate may react chemically with clays in the formation – either of these processes can reduce the near-well permeability dramatically. Completions may further reduce the productive capacity of the well: the well may be cased and perforated (reducing the inflow area compared to an open-hole completion), partially penetrating (reduced thickness for inflow), or internal gravel-packed (pressure loss through perforations, gravel, and screen). On the other hand, the pressure-drop in the near-well area can sometimes be increased. This could be accomplished by fracture treatments or acid treatments. Attempts to lower the pressure drop in the near-well area are often called "stimulation."

I will present some sketches of these situations in this assignment.

4.3 Radial Composite Model for Damage and Stimulation

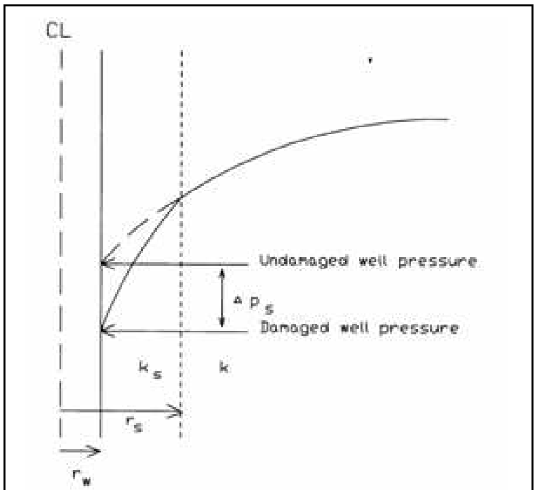

Fig.18 – From the centerline (CL), the wellbore extends to r_w. A region of altered permeability, k_s, extends r_w to the skin radius, r_s. The unaltered permeability, k, then extends to the outer radius, r_e. From Horne.

The simplest model for well bore alteration is a radial composite model. The permeability is assumed to be altered from the formation permeability, k , to the "altered" or "skin" permeability, k_s , in a region $r_w \le r \le r_s$ (Fig. 18). For situations with $k_s < k$ (damage), this results in an increased pressure drop, Δp_s . Note that Δp_s is NOT the pressure drop across the skin region! It is the *change* in pressure drop for the composite model (the model with altered permeability) compared with the model with no altered permeability region. For damage, Δp_s is positive whereas Δp_s is negative for stimulation. I guarantee some students will confuse Δp_s with $p(r_s) - p(r_w)$. Look at Fig.18, and make certain that you understand the difference!

We can now write expressions for the pressure drops using our knowledge of the radial flow equation and series flow. The pressure drop across the skin region is

$$[p(r_s) - p(r_w)]_s = \frac{q\mu B}{2\pi k_s h} \ln\left(\frac{r_s}{r_w}\right) \qquad \ldots\ldots\ldots\ldots (1)$$

Note that this pressure drop increases as r_s increases and k_s decreases: this makes senses, because thicker, lower permeability skin zones cause more pressure drop, and more damage. If the permeability had not been altered, the pressure drop would be

$$[p(r_s) - p(r_w)]_0 = \frac{q\mu B}{2\pi kh} \ln\left(\frac{r_s}{r_w}\right) \qquad \text{…………… (2)}$$

Combining Eqns. (1) and (2), we get an equation for Δp_s :

$$\begin{aligned}\Delta p_s &= [p(r_s) - p(r_w)]_s - [p(r_s) - p(r_w)]_0 \\ &= \frac{q\mu B}{2\pi h} \ln\left(\frac{r_s}{r_w}\right)\left[\frac{1}{k_s} - \frac{1}{k}\right] \qquad \text{........ (3)} \\ &= \frac{q\mu B}{2\pi kh} \ln\left(\frac{r_s}{r_w}\right)\left[\frac{k}{k_s} - 1\right]\end{aligned}$$

Examine the term $\left[\frac{k}{k_s} - 1\right]$. Note that Δp_s will be positive when $k>k_s$, and negative when $k<k_s$. If the well is much damaged, and $k_s << k$, then this term will be positive, and Δp_s will tend to be large (and could approach infinity). If the well is stimulated, $k_s >> k$, and the and $\left[\frac{k}{k_s} - 1\right]$ can be no smaller than -1. This is an important point: the amount of damage is theoretically unlimited, but the maximum possible stimulation is limited. The pressure drop $p(r_s) - p(r_w)$ will *always* be positive for a producing well, Δp_s can be negative (for stimulation) or positive (for damage). The magnitude of the pressure drop also increases as the dimensionless skin radius $\left(\frac{r_s}{r_w}\right)$ increases due to the term $\ln\left(\frac{r_s}{r_w}\right)$. This makes sense: thicker skin, more effect. Finally, the pressure drop is scaled by the group $\frac{q\mu B}{2\pi kh}$. Thus, for example, higher flow rates imply higher Δp_s.

Let's examine this group, $\frac{q\mu B}{2\pi kh}$, more closely. Because the left hand side (LHS) of Eqn. (3) is a pressure, and the terms $\ln\left(\frac{r_s}{r_w}\right)$ and $\left[\frac{k}{k_s} - 1\right]$ are dimensionless, the dimensions of $\frac{q\mu B}{2\pi kh}$ must be pressure. That is, $\frac{q\mu B}{2\pi kh}$ scales the dimensionless groups $\ln\left(\frac{r_s}{r_w}\right) \times \left[\frac{k}{k_s} - 1\right]$. The pressure drop is proportional to this group; increasing q has the same effect as decreasing h or k by the same factor. We will use this scaling later in the discussion of skin below: it is the basis of dimensionless pressure for radial flow.

4.4 A Lumped Model for Damage and Stimulation: Skin Effect

As it turns out, well test analysis allows us to estimate Δp_s but it does not allow us to estimate either k_s or r_s. These would be nice to know, it is just that the time scales and physical limitations of well tests usually prevent their estimation. For this reason, instead of the product $\ln\left(\frac{r_s}{r_w}\right)\times\left[\frac{k}{k_s}-1\right]$ reservoir engineers usually must work with another variable called skin and represented as s. Rewriting Eqn. (3),

$$\begin{aligned}\Delta p_s &= \frac{q\mu B}{2\pi kh}\ln\left(\frac{r_s}{r_w}\right)\left[\frac{k}{k_s}-1\right] \\ &= \frac{q\mu B}{2\pi kh}s\end{aligned} \tag{4}$$

The definition of skin in terms of the composite radial model is

$$s = \ln\left(\frac{r_s}{r_w}\right)\left[\frac{k}{k_s}-1\right] \tag{5}$$

and in terms of pressure drop s is

$$s = \frac{2\pi kh}{q\mu B}\Delta p_s \tag{6a}$$

in consistent units, or

$$s = \frac{0.00708kh}{q\mu B}\Delta p_s \tag{6b}$$

in field units.

We can use Eqn. (5) to obtain a skin value if we have a model for the radial distribution of permeability, whereas we will use Eqn. (6) to estimate s from Δp_s, which can be inferred from a well test.

4.5 Skin as a Dimensionless Pressure

The skin factor s is dimensionless. In fact, it can be thought of as the *dimensionless pressure drop* due to near-well permeability alteration. In radial flow, the dimensionless pressure and dimensional pressure are related by

$$p_D = \frac{2\pi kh}{q\mu B}\Delta p \tag{7a}$$

in consistent units, or

$$p_D = \frac{0.00708kh}{q\mu B}\Delta p \tag{7b}$$

in field units. We will use these definitions extensively in well test design and analysis.

4.6 Inflow Equation Including Skin

We know the steady-state radial flow of incompressible liquids can be expressed as

$$q = \frac{2\pi kh}{\mu B}\frac{(p - p_w)}{\ln\left(\frac{r}{r_w}\right)}$$

Solving for $(p - p_w)$,

$$(p - p_w) = \frac{q\mu B}{2\pi kh}\ln\left(\frac{r}{r_w}\right)$$

Using the concept of Δp_s

$$(p - p_w) = \frac{q\mu B}{2\pi kh}\ln\left(\frac{r}{r_w}\right) + \Delta p_s$$

$$(p - p_w) = \frac{q\mu B}{2\pi kh}\ln\left(\frac{r}{r_w}\right) + \frac{q\mu B}{2\pi kh}s$$

$$(p - p_w) = \frac{q\mu B}{2\pi kh}\left[\ln\left(\frac{r}{r_w}\right) + s\right] \qquad (8)$$

$$q = \frac{2\pi kh(p - p_w)}{\mu B\left[\ln\left(\frac{r}{r_w}\right) + s\right]}$$

Skin is simply added to the log term in the denominator of the inflow equation. So we can "visualize" *s* as a sort of additional distance that the fluid must flow. Of course, it is actually dimensionless.

4.7 Range of Skin Values

Skin values can easily be computed using Eqn. (5). Such a plot is shown in Fig.19. The most important thing to note is how very large the positive (damage) skins can be; the absolute value of the stimulated skins is very small in comparison (for the same permeability ratio k_s / k and radius ration r_s / r .

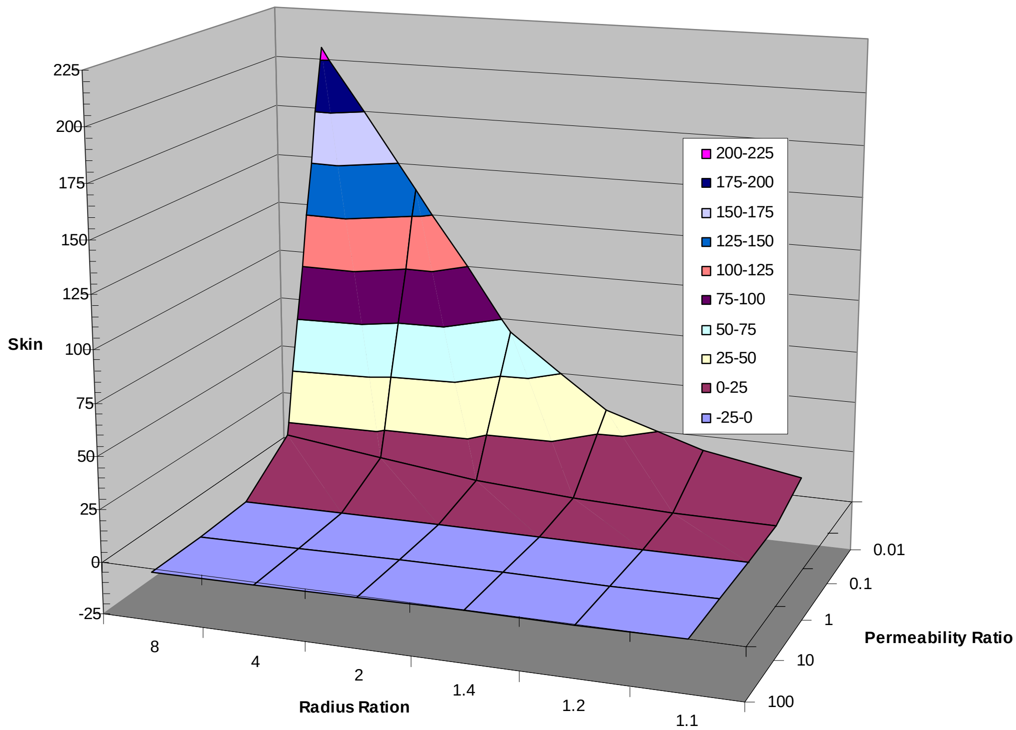

Fig.19 – Skin as a function of size and permeability of altered zone.

This behavior is easy to understand if we consider the pressure profiles. Rather than looking at the profiles in r (Fig. 18), it is easier to plot them in $\ln(r)$ (Fig.20). Note that the profiles take a different form if we assume constant rate versus constant pressure drop.

4.8 Effect of Skin on Rate

If we examine the radial inflow equation with skin [Eqn. (8)], we can see flow rate for a given available pressure drop is inversely related to $\left[\ln\left(\frac{r}{r_w}\right)+s\right]$. For typical well spacings, $r_e / r_w \approx 2000$ so than the logarithm will have a value of about 8 (note that our analysis isn't very sensitive to the ratio because we are taking its log). This means that a skin value of 8 roughly cuts the flow rate in half, or of -4 will roughly double the flow rate. Keep in mind that this simple analysis does not consider tubing pressure drops.

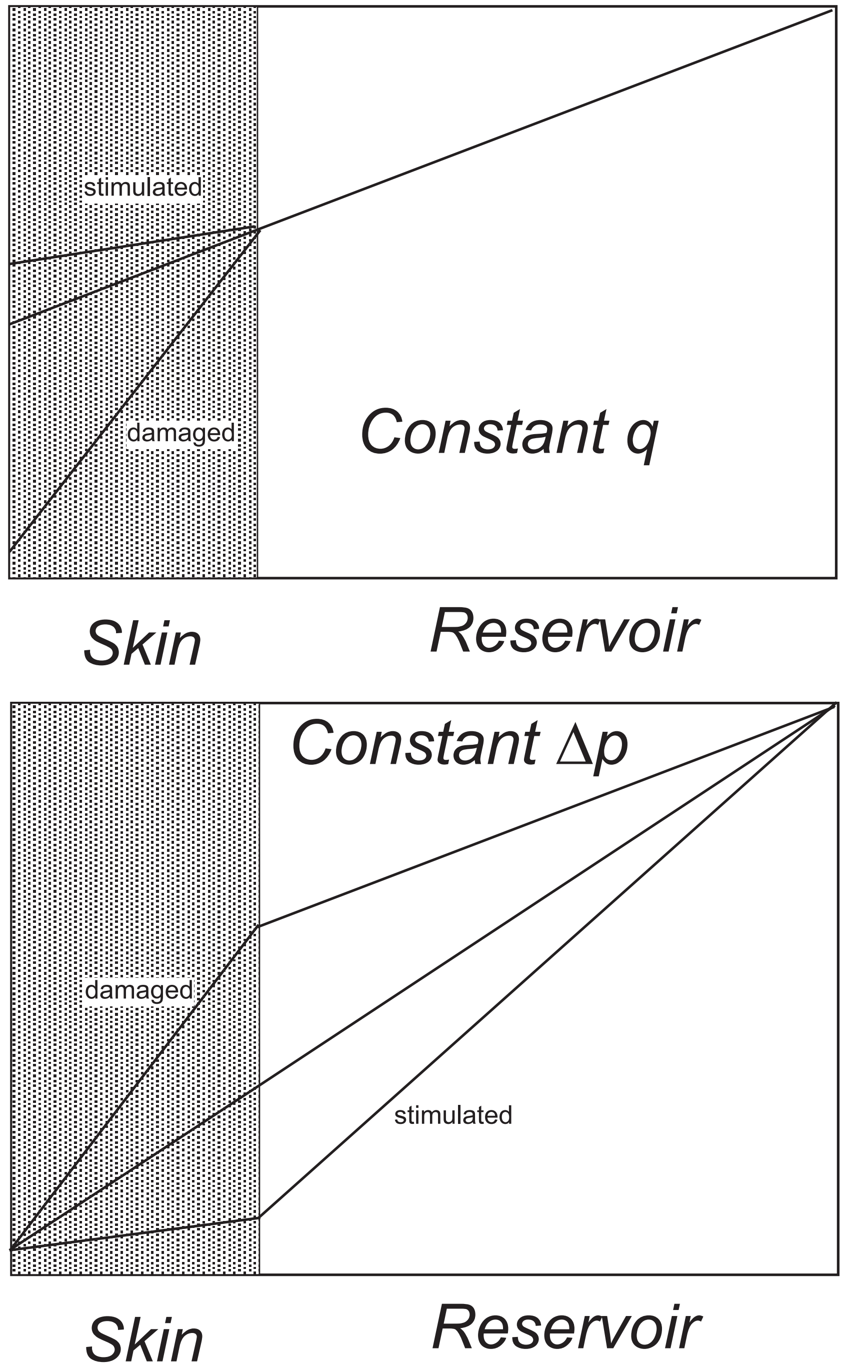

Fig.20 Radial pressure profiles. The vertical axis is pressure, the horizontal axis is the log of radius. The left side of the figure is the well, the right side is the outer boundary. The hatched region has altered permeability.

4.9 Flow Efficiency

The flow efficiency of a well is simply the ratio of its unaltered flow capacity to it actual flow capacity. This is [from Eqn. (8)],

$$F_E = \frac{q(s)}{q(s=0)}$$

$$= \frac{\ln\left(\frac{r_e}{r_w}\right)}{\ln\left(\frac{r_e}{r_w}\right) + s} \qquad (9)$$

Eqn. (9) applies to steady-state systems only. As noted by Horne, F_E is harder to interpret in general (for example, for transient systems). It is usually more consistent to use *s*, but flow efficiency can be a useful and simple-to-explain quantification of rate change due to damage or stimulation.

4.10 Apparent well bore Radius

We can also express the effect of skin as an equivalent well bore radius, using the radial inflow equation with skin [Eqn. (8)]:

$$\frac{2\pi kh\Delta p}{\ln\left(\frac{r_e}{r_e}\right) + s} = \frac{2\pi kh\Delta p}{\ln\left(\frac{r_{wa}}{r_e}\right)}$$

Rearranging,

$$\ln\left(\frac{r_e}{r_{wa}}\right) = \ln\left(\frac{r_e}{r_w}\right) + s$$

$$\frac{r_e}{r_{wa}} = \exp\left[\ln\left(\frac{r_e}{r_w}\right) + s\right] \qquad (10)$$

$$\frac{r_e}{r_{wa}} = e^s\left(\frac{r_e}{r_w}\right)$$

$$r_{wa} = r_w e^{-s}$$

Positive skins cause an additional resistance; this effect is similar to reducing the well bore radius. Conversely, negative skins are analogous to increasing the well bore radius.

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